PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION

I. D. #6019
RESOLUTION E-4003
October 5, 2006

R E S O L U T I O N

Resolution E-4003. Pacific Gas and Electric Company (PG&E) requests that its Reliability Performance Incentive Mechanism (RPIM) be made a part of its Distribution Revenue Adjustment Mechanism (DRAM) and that a penalty of $2.8 million be adopted for its first year 2005 results. Approved.

By Advice Letter 2800-E dated March 9, 2006.

SUMMARY

The Commission approves PG&E's Advice Letter 2800-E submitted to make its Reliability Performance Incentive Mechanism (RPIM) a part of its Distribution Revenue Adjustment Mechanism (DRAM), and to adopt for 2005 a RPIM penalty of $2.8 million. PG&E is to apply the same methodology to outage data supporting the RPIM results it files in future years, retain records of all corrections to outage data, and submit with future RPIM filings the results of an audit of current-year outage data.

BACKGROUND

Electric utilities are required to report reliability indices to the Commission

Decision (D) 96-09-045, effective September 4, 1996, requires electric utilities to maintain information adequate to calculate reliability indices by circuit, district, and division. Each electric utility is required to report reliability indices in an annual report to Energy Division by March 1 of the year following the calendar year reflected by the data used to calculate the indices. This Decision defines three system-wide reliability indices:

System Average Interruption Duration Index (SAIDI)
SAIDI is defined as the total minutes of sustained customer interruption divided by the total number of customers, expressed in minutes per customer per year.

System Average Interruption Frequency Index (SAIFI)
SAIFI is defined as the total number of sustained customer interruptions divided by the total number of customers, expressed in interruptions per customer per year.

Momentary Average Interruption Frequency Index (MAIFI)

MAIFI is defined as the total number of momentary customer interruptions divided by the total number of customers, expressed as momentary interruptions per customer per year.

The Commission defines a sustained outage as an outage that lasts 5 minutes or more; a momentary outage lasts less than 5 minutes.

D.96-09-045 allows electric utilities to exclude planned outages and excludable major events from reliability indices calculations.

Appendix A of D.96-09-045 defines an excludable major event as (a) an event that is caused by earthquake, fire, or storms of sufficient intensity to give rise to a state of emergency being declared by the government, or (b) any other disaster not in (a) that affects more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event.

In 2004 the Commission Adopted a RPIM for PG&E
In Application 02-11-017, PG&E's Test Year 2003 General Rate Case, an Assigned Commissioner's Ruling established a separate phase of the proceeding in order to evaluate PG&E's readiness for storms that occurred in December 2002 and PG&E's response to them. The Commission's Decision (D) 04-10-034 in the matter included Ordering Paragraph 8. that adopted a RPIM. Table 1 below shows the target metrics and incentive levels adopted in the decision. PG&E is rewarded for achieving outage duration and frequency levels below the lower limits of the deadbands, and is penalized for SAIDI and SAIFI values that rise above the deadbands.

Table 1. PG&E's Target Metrics and Incentive Levels for 2005

	Liveband Lower Limit	*Deadband Lower Limit*	*Target for 2005*	*Deadband Upper Limit*	*Liveband Upper Limit*
SAIDI excluding Major Events (minutes)	139.20	155	165	175	190.80
SAIFI excluding Major Events (Interruption/Customer)	1.15	1.30	1.40	1.50	1.65
Max Annual Reward/Penalty	+ $12 million	None	None	None	- $12 million
SAIDI Per Unit Incentive	+ $759,494 / minute change in SAIDI	None	None	None	- $759,494 / minute change in SAIDI
SAIFI Per Unit Incentive	+ $800,000 / 0.01 change in SAIFI	None	None	None	- $800,000 / 0.01 change in SAIFI

PG&E Discovered Errors in its Reliability Statistics and Hired EPRI Solutions to Correct Data to be Filed in its 2005 RPIM.

In early 2005 a PG&E internal Quality Assurance (QA) review revealed errors in recorded reliability statistics that could affect its 2005 RPIM filing. By incorrectly classifying as momentary outages all outages less than 6 minutes PG&E would under-report the SAIDI index of sustained outages, which is part of the RPIM. D.96-09-045 defined the momentary outages that could be excluded from the SAIDI calculation to be limited to only 5 minutes duration. The MAIFI index would drop correspondingly but is not a part of the RPIM.
Therefore PG&E reported to the Energy Division on June 21, 2005, that it had hired EPRI Solutions to analyze its January thru April 2005 reliability data.

PG&E met with Energy Division on October 20, 2005 to discuss the completed study which concluded that PG&E had under-recorded SAIDI by 2.0% and over-recorded SAIFI by 1.7% during this period, the first 4 months of 2005. In other words the average customer in PG&E's system was without service 1.3 minutes longer but had slightly less or 0.008 fewer interruptions.

Based on these results PG&E revised its on-going internal procedures and software to correctly record outage data for the remainder of 2005 as it unfolded. Looking backward PG&E also revised reliability indices previously reported to the Commission starting with 1988. The corrected data is reported as corrected in Section 1 of PG&E's March 1, 2006 annual electric distribution reliability report.

PG&E filed Advice Letter 2800-E on March 9, 2006 proposing to revise its electric Preliminary Statement Part CZ – Distribution Revenue Adjustment Mechanism (DRAM) to incorporate the results of the RPIM each year and for 2005, to approve the $2,810,128 penalty results of the RPIM.
PG&E relied upon the SAIDI and SAIFI values reported in its March 1, 2006 report to calculate rewards or penalties under the RPIM for 2005. Electric outages that occurred on December 18, 2005, December 19, 2005, December 20, 2005, and December 31, 2005 were classified as excludable major events and excluded from the final system SAIDI and SAIFI calculations.

PG&E reported 178.7 minutes/customer for SAIDI, which is 3.7 minutes/customer higher the 175 minutes/customer limit of the deadband resulting in the penalty of $2,810,128.[1] The SAIFI value of 1.344, however, fell within the deadband of 1.3 to 1.5 interruptions per customer, and triggered no reward or penalty.

NOTICE

Notice of AL 2800-E was made by Publication in the Commission's Daily Calendar on March 13, 2006.

1 3.7 minutes x $759,494/minute = $2,810,128.

PROTESTS

The Commission has received no protests.

DISCUSSION

The high dollar values associated with unit values of SAIFI and SAIDI require careful review of PG&E's calculations, outage data processing, and reading of Decisions.

PG&E Should Document All Corrections to Outage Data.
On June 6, 2006, at staff's request PG&E provided data on customer-minutes [2] and customer-interruptions [3] associated with each outage event in 2005. Energy Division staff used this information to check reported SAIDI and SAIFI values and found a difference of 0.090 minutes/customer for SAIDI, corresponding to $87,342.1 This amounts to an increase of 485,219 customer minutes. On August 21, 2006, PG&E responded to further inquiry from Energy Division, reporting eleven modifications of outage data made between February 23, 2006, and March 27, 2006 regarding outage events on December 18 and December 31, 2005. However, since the events were categorized as major events they were excluded from the index calculations and had no effect on the final 2005 SAIDI value or the RPIM penalty value.

On September 12, 2006, PG&E stated there were actual nine modifications took place between February 23, 2006 and March 27, 2006. Two of these modifications were inadvertent duplication due to query error. There is only one of these nine outage modifications has an effect on SAIDI calculation. This was an outage occurred on December 31, 2005, in the Peninsula Division, on the Woodside 1101 circuit, that resulted in a net reduction of 149,435 customer minutes of interruptions and 0.03 minute/customer in SAIDI.

PG&E also reported that two additional outages occurred in 2005 (besides the nine outages mentioned above) were not entered into their database until after February 23, 2006. One of these outages occurred on December 31, 2005, and had 488,124 customer minutes of interruptions (0.09 minutes/customer). Since this outage occurred on an excludable day, it does not affect the final reliability indices calculations. However, the second outage with 7,650 customer minutes of interruptions (0.0014 minute/customer) that occurred on November 10, 2005, should have included in SAIDI calculation.

PG&E can not explain the remaining 138,880 customer minutes or 0.03 minute/customer of SAIDI (485,219 customer minutes - (-149435+7650+488124) customer minutes). PG&E stated that their OUTAGE program retains only the most recent modification. Therefore, the nine outages modified between February and June 2006 may have also modified their customer

[2] Customer minutes are defined as the product of the number of customers involved in a sustained outage and the duration of the sustained outage.

[3] Customer interruptions are defined as the product of the number of customers involved in a sustained outage and the frequency of that circuit interruption.

minute values. But since a query will return only the most recent change, older changes may have been "overwritten" by the most recent modification.

Appendix C summarizes the net effect of PG&E's outage data modifications. The final system SAIDI including outage data modifications and 0.03 minute/customer of unexplained SAIDI is 178.73 minutes/customer, which has no affect on the total RPIM penalty.

Energy Division recommends that the Commission requires PG&E to retain records of all modifications to outage data. This includes evidence to support the modifications, PG&E staff who initiated the changes, and dates and effects of these changes.

PG&E Used Multiple Criteria, Some Subjective, to Define the Beginning and End of an Excludable Major Outage Event.

Beginning and End of an Excludable Major Outage EventD. 96-09-045 defines an excludable major event as a disaster that affects more than 15% of the system facilities or 10% of the utility's customers. However, the Commission does not have a policy in place to define the beginning or end point of an excludable major outage event.

PG&E uses a 48-hour sliding window to identify when 10 percent of the Company's customers have incurred a sustained outage. After identifying that an event has risen to the level of an excludable major outage, PG&E reviews the number of customer interruptions that occurred on the days before and after the event. The time-period of the major event is determined by including those consecutive days that exceed 30,000 sustained customer-interruptions per day. PG&E indicates that the 30,000 customer-interruptions value is based on its experience with major events, which are typically storm-related.

PG&E has been using this process to interpret the beginning or end of an excludable major outage event since 1996. The Commission adopted PG&E's RPIM under this assumption. Hence, the Commission should continue allowing PG&E to use this method. But Energy Division recommends the Commission require PG&E to submit data to support the time spans of each year's excludable major outage events in its annual RPIM advice letter filing.

Outage Exclusions due to a Proclamation of a State of Emergency

Appendix A of D.96-09-045 defines a state of emergency declared by the governor as constituting an excludable major event, independent of the numbers of customers or interruptions. However, the Commission has no policy on excluding outages in a Division that includes some counties in a state of emergency along with others not having such a status.

The Governor issued three proclamations relating to the storms in mid-December 2005. The proclamations were made after the fact and dated January 2, January 3, and January 12, 2006. PG&E obtained copies of the Governor's proclamations that 34 counties, anmed in Appendix A, were in a state-of-emergency.

The proclamations refer to severe rainstorms that commenced on December 19, 2005. PG&E states the storms actually commenced on December 18, 2005. PG&E states that the number of outages, weather data, media coverage of the storm, and PG&E's twelve Operations Emergency

Centers (OECs) that it activated before 2:00pm on December 18, 2005, all confirm the December 18 date.

PG&E then used the following process to determine whether to exclude outages in a given Division from the calculation of system reliability indices for the major event spanning December 18 through December 20, 2005. PG&E:

- Reviewed the affected county boundaries relative to its Division boundaries.
- Determined the percentage of the area of each division covered by the counties identified in the Governor's proclamations.
- Reviewed outage data from the affected divisions.
- Found that twelve of PG&E's divisions had more than fifty percent of their area covered by counties declared to be in a state of emergency: North Bay, North Coast, North Valley, Peninsula, Sacramento, Sierra, Stockton, Diablo, East Bay, Fresno, Los Padres and Mission (Appendix B).
- Selected a time span of December 17 through December 23, 2005 in order to determine the outage levels on the day before the storm began, and the outage levels following the storm. For most divisions, outage levels returned to "normal" on December 19 or December 20, 2005.
- The data reviewed included the numbers of sustained outages, customer interruptions, and customer minutes, as well as the corresponding data for the same December time periods in the years 2000-2004.
- Finally the comparison of outage data from the December 2005 storm to the previous five years of December outage data led PG&E to exclude outages beginning December 18, one day earlier than the Governor's earliest proclamation of December 19, for seven of its divisions: Diablo, East Bay, North Bay, North Coast, Peninsula, Sacramento and Stockton.
- In reviewing the daily outage data for December 19th and 20th, PG&E further concluded that it was reasonable to exclude outages for North Coast, Peninsula and the Sacramento divisions for December 19th, and the North Coast division for December 20th.

PG&E's method of excluding outages, while systematic, involves subjective judgments such as 50% of a county being declared in a state of emergency. Therefore, the Energy Division recommends the Commission direct PG&E to include in its annual RPIM filing all data considered in its decisions to include or exclude outages from its calculation of reward or penalty.

The ability of PG&E to collect accurate and timely distribution outage data and maintain Quality Control and Quality Assurance Programs determine the accuracy of its calculation of reliability indices.

PG&E defines the start of an outage event as the earliest time of "first no light" (FNL) or equipment operation/alarm. PG&E defines the end of an outage event when all restorable customers are returned to service, or at the time it is declared non-restorable by either a field person or operator.

Customers are considered "not restorable" when a:

- Customer requests PG&E to de-energize or not restore power when outage only affects that customer.

- Government agency requests PG&E to de-energize or not restore power.
- System-wide or localized natural disaster that prevents PG&E from accessing an area to safely restore power.

Of the many outages occurring in a normal week, PG&E indicates that its operating personnel at each electric control center perform a weekly data quality control review of at least three outages in excess of 100,000 customer-minutes, corresponding to a review of approximately ten percent of all sustained outages.[4] Operating personnel correct errors as they are detected and communicate "lessons learned" as necessary with the other control center personnel.

PG&E points out that the sample size of 3 per week was not statistically determined, but rather based on judgment with consideration given to the other higher priority tasks operating personnel at each electric control center must perform round-the-clock.

PG&E states that it plans to implement in the next few months a similar random sample review process for mapping departments. PG&E mapping personnel are responsible for recording outages in the Company's OUTAGE database. OUTAGE is the program mapping personnel uses to enter outage data they receive from control centers.

In addition to random sampling, PG&E extracts and compares data from both of the above databases, the Company's Integrated Logging Information System (ILIS) and the OUTAGE database. ILIS is the program that PG&E operating personnel use at control centers. By comparing data from these two sources, PG&E can identify potential errors in the following areas in a) outage start and end times; b) un-posted outages; c) duplicate outages; and in planned vs. unplanned outages (i.e., appropriately categorizing outages).

PG&E states that its operating and/or mapping personnel reviews and corrects potential errors after comparisons. PG&E mapping personnel and distribution engineers review outages that exceed 100,000 customer-minutes to assure accurate outage reporting. PG&E indicates that the percentage of sustained outages exceeding 100,000 customer outage minutes for the five year period from 2001-2005 excluding major events is 9.3%, and 10.7% with major events included. These values represent approximately 2,060 outages per year with major events excluded and approximately 2600 outages per year with major events included.

PG&E has implemented a variety of communication and training measures related to outage reporting accuracy over the last year, but has not yet compiled information to determine the results of the various steps the company is taking that relate to outage reporting accuracy. However, PG&E is planning to perform an outage-reporting audit in the 4th quarter of 2006 and anticipates the results will provide a useful indication of outage reporting accuracy.

Energy Division staff recommends the Commission require PG&E to conduct an annual outage reporting internal audit. The result of this audit should be submitted with the annual RPIM advice letter.

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4 (3 outages/week/control center) x (52 weeks) x (17 control centers) ≈ 2,600 outages reviewed annually at the electric control centers. There were approximately 24,000 sustained outages in 2005.

COMMENTS

This is an uncontested matter in which the resolution grants the relief requested. Accordingly, pursuant to PU Code 311(g)(2), the otherwise applicable 30-day period for public review and comment is being waived.

FINDINGS

1. Decision (D) 96-09-045, effective September 4, 1996 requires electric utilities to maintain information adequate to calculate reliability indices by circuit, district, and division. Each electric utility is required to report reliability indices in an annual report to Energy Division.

2. System Average Interruption Duration Index SAIDI is defined as the total minutes of sustained customer interruption divided by the total number of customers, expressed in minutes per customer per year.

3. System Average Interruption Frequency Index SAIFI is defined as the total number of sustained customer interruptions divided by the total number of customers, expressed in interruptions per customer per year.

4. D.96-09-045 allows electric utilities to exclude planned outages and excludable major events from reliability indices calculations.

5. A Governor’s Proclamation of a State of Emergency for a day justifies excluding associated outages from the reliability indices.

6. The Commission has no policy on interpreting the beginning or end of an excludable major outage event, or how to treat outages in a Division that includes some counties in a state of emergency and others that are not.

7. Ordering Paragraph 8. of Decision 04-10-034 adopted a Reliability Performance Incentive Mechanism under which PG&E is rewarded for achieving outage duration and frequency levels below the lower limits of the deadbands, and is penalized for SAIDI and SAIFI values that rise above the deadbands.

8. PG&E discovered a systematic data error in its early 2005 reliability data. It eliminated the source of error beginning with outage data for May 2005 data and contracted with EPRI Solutions to develop a percentage error for earlier data based on a statistical sample from its January thru April 2005 reliability data,

9. The EPRI study quantified under-reporting of SAIDI values and over-reporting of SAIFI values during this period. PG&E filed adjusted reliability data for this period in its March 1, 2006, annual electric distribution reliability report.

10. PG&E in this Advice Letter requests authority to revise Preliminary Statement Part CZ to

incorporate the RPIM in its DRAM and to book a $2,810,128 penalty for its 2005 RPIM results based on corrected outage data.

11. During Energy Division analysis PG&E reported eleven modifications of outage data PG&E made between February 23, 2006, and March 27, 2006 regarding outage events on December 18 and December 31, 2005. The 2 days were categorized as major events and therefore excluded from the index calculations and had no effect on the final 2005 SAIDI value or the RPIM penalty value.

12. PG&E indicates that its operating personnel at each electric control center perform a weekly review of at least three outages or approximately ten percent of all sustained outages.

13. PG&E mapping personnel and distribution engineers regularly review outages that exceed 100,000 customer-minutes in order to improve outage-reporting accuracy.

14. PG&E plans to perform an outage-reporting audit in the 4th quarter of 2006.

15. Energy Division recommends that the Commission require PG&E to retain records of all corrections to outage data, including the data before and after corrections, PG&E staff who initiated the changes, and dates and effects of the changes.

16. Energy Division also recommends the Commission require PG&E to submit the following information with its future RPIM filings:

- Results of an annual outage reporting internal audit.
- Data to support the time spans of each year’s excludable major outage event.
- Data to support outage exclusions during each declared state of emergency.

THEREFORE, IT IS ORDERED THAT:

1. PG&E’s Advice Letter 2800-E is approved in order to incorporate PG&E’s Reliability Performance Incentive Mechanism (RPIM) as part of its Distribution Revenue Adjustment Mechanism (DRAM), and to adopt for 2005 a RPIM penalty of $2,810,128.

2. Future PG&E RPIM advice letters shall include:
   a) Data supporting the start and end time of each excludable major event;
   b) Data supporting each event excluded due to a declared state of emergency; and
   c) The results of an audit of the outage data used to calculate the RPIM incentive.

3. PG&E is to retain records of all corrections to outage data, including the data before and after the change, PG&E staff that initiated the changes, and dates and effects of the changes.

4. This Resolution is effective today.

I hereby certify that the Public Utilities Commission adopted this Resolution at its regular meeting on October 5, 2006. The following Commissioners voting favorably thereon:

STEVE LARSON
Executive Director

Appendix A

PG&E submitted the following data to the Energy Division on 6/9/2006:

Counties named in the Governor's proclamations of State of Emergency

January 2, 2006 Proclamation – Del Norte, Humboldt, Mendocino, Napa, Sacramento, Sonoma, and Trinity

January 3, 2006 Proclamation – Butte, El Dorado, Lake, Lassen, Marin, Nevada, Placer, Plumas, San Joaquin, San Mateo, Sierra, Siskiyou, Solano, Sutter, Yolo, and Yuba

January 12, 2006 Proclamation – Alameda, Alpine, Amador, Colusa, Contra Coast, Fresno, Kings, San Luis Obispo, Santa Cruz, Shasta, and Tulare

Appendix B

PG&E submitted the following data to the Energy Division on 6/9/2006:

Relationship between PG&E Division Boundaries and County Boundaries for the December 18-20 Storm Event

PG&E Division	*Percent of Area of Division Comprised of Counties Declared to be in a State of Emergency*	*Dates that Division Outage Data was Excluded from System Outage Data*
North Coast	100%	December 18, 19, 20
North Bay	100%	December 18
East Bay	100%	December 18
Diablo	100%	December 18
Sierra	100%	No exclusions
Mission	100%	No exclusions
Fresno	99%	No exclusions
Peninsula	98%	December 18, 19
Sacramento	98%	December 18, 19
Stockton	68%	December 18
North Valley	65%	No exclusions
Los Padres	54%	No exclusions
Kern	13%	No exclusions
Central Coast	9%	No exclusions
De Anza	8%	No exclusions
Yosemite	7%	No exclusions
San Francisco	2%	No exclusions
San Jose	0%	No exclusions

Appendix C

Net Effect on System SAIDI from PG&E's Outage Data Modifications						
Line #	**Description**	**Division or System**	**Date**	**SAIDI**	**SAIFI**	**Comment**
1	**Step 1: January to April adjustment associated with EPRI Solutions' Report**					
2	Starting point: January - April	SYSTEM	Jan - Apr 2005	65	0.449	
3	Adjustment Factors (+2.0% for SAIDI and -1.7% for SAIFI, from EPRI report)			0.02	-0.017	
4	Resulting adjustment (line 2 multiplied by line 3)			1.3	-0.008	
5						
6	**Step 2: Annual adjustment from EPRI Solutions' Report**					
7	Starting point: January - December data	SYSTEM		236.815	1.487	Staff Calculated system SAIDI based on data submitted by PG&E on 6/9/2006
8	Adjustment values (from line 4)			1.3	-0.008	
9	Subtotal 1 (line 7 plus line 8)			238.12	1.479	
10	**Step 2A: Adjust for outage record modifications submitted by PG&E on 9/13/06**					
10a		PENINSULA	31-Dec	-0.03		Reduce 149,435 customer minutes
10b		NORTH COAST	10-Nov	0.0014		7,650 customer minutes
10c		NORTH COAST	31-Dec	0.09		488,124 customer minutes
10d	Subtotal 2 (Sum of line 10a, 10b, and 10c)			0.064		
10e	Subtotal 3 (line 9+10d)			238.179		
11	**Step 3: Subtract excluded days**					
12	Starting point: Excludable December data	DIABLO	18-Dec	0.38	0.003	
13		EAST BAY	18-Dec	0.48	0.003	
14		NORTH BAY	18-Dec	0.38	0.002	
15		NORTH COAST	18-Dec	0.75	0.003	
16		PENINSULA	18-Dec	1.03	0.004	
17		SACRAMENTO	18-Dec	0.39	0.002	
18		STOCKTON	18-Dec	0.18	0.001	
19		NORTH COAST	19-Dec	0.27	0.001	
20		PENINSULA	19-Dec	0.06	0.001	
21		SACRAMENTO	19-Dec	0.08	0.000	
22		NORTH COAST	20-Dec	1.11	0.003	
23		SYSTEM	30-Dec	2.23	0.009	
24		SYSTEM	31-Dec	51.98	0.103	
24a		PENINSULA	31-Dec	-0.03		Reduce 149,435 customer minutes
24b		NORTH COAST	31-Dec	0.09		488,124 customer minutes
25	Subtotal (Sum of lines 12 thru 24b)			59.38	0.135	
26						
27	**Step 4: Calculate final value**					
28	2005 SAIDI & SAIFI excluding major events and adjusted for EPRI Solutions Report (line 9 minus line 25)			**178.73**	**1.344**	